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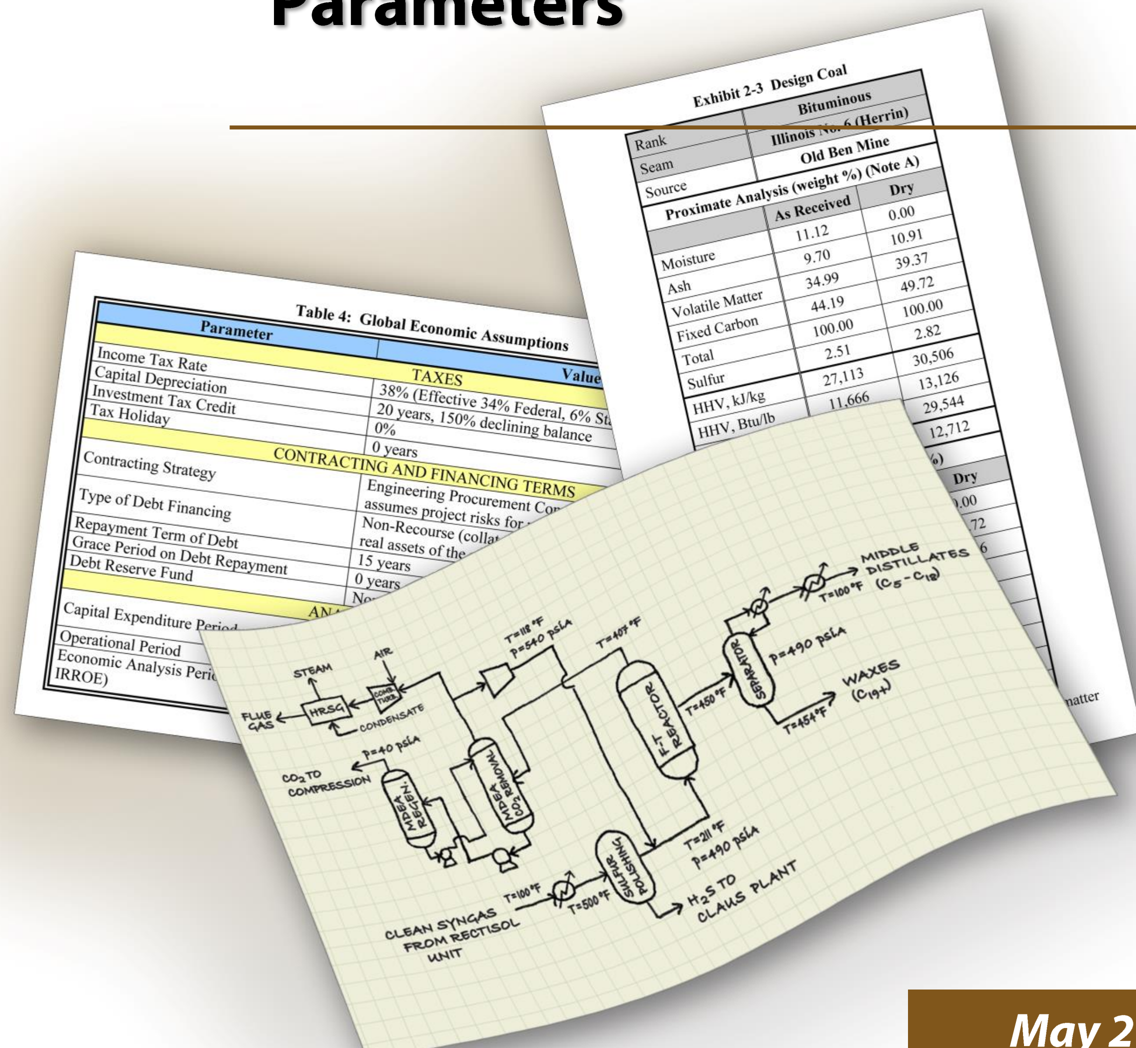
QUALITY GUIDELINES FOR ENERGY SYSTEMS STUDIES

Process Modeling Design Parameters



May 2014

DOE/NETL-341/051314

NATIONAL ENERGY TECHNOLOGY LABORATORY

U.S. DEPARTMENT OF ENERGY

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Process Modeling Design Parameters in NETL Studies

DOE/NETL-2014/051314

Final Report

May 13, 2014

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DOE Contract Number DE-FE0004001

Acknowledgments

This report was prepared by Energy Sector Planning and Analysis (ESPA) for the United States Department of Energy (DOE), National Energy Technology Laboratory (NETL). This work was completed under DOE NETL Contract Number DE-FE0004001. This work was performed under ESPA Task 341.02.33.

The authors wish to acknowledge the excellent guidance, contributions, and cooperation of the NETL staff, and peer reviewers, particularly:

James Black, NETL, Office of Program Performance and Benefits (OPPB)
Kristin Gerdes, NETL, OPPB
Michael Matuszewski, NETL, OPPB
Walter Shelton, NETL, OPPB
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Luke Rogers, Southern Company
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Robert D. Brasington, C12 Energy

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Acronyms and Abbreviations

ACI	Activated carbon injection
AR	As-received
CFB	Circulating fluidized bed
CO_2	Carbon dioxide
CoP	ConocoPhillips
EPRI	Electric Power Research Institute
FGD	Flue gas desulfurization
ft	feet
GE	General Electric Energy
H_2O	Water
IEA-GHG	International Energy Agency – Greenhouse Gas R&D Programme
ISO	International Standards Organization
HP	High pressure
HRSG	Heat recovery steam generators
HTS	High temperature shift
IGCC	Integrated gasification combined cycle
IP	Intermediate pressure
kPa	Kilopascal
lb/hr	Pounds per hour
lb/ft^3	Pounds per cubic foot
LK-PLOCK	Lee-Kesler-Plöcker equation of state
LTS	Low temperature shift
m^3	cubic meter
MMacf	Million actual cubic feet
MMacm	Million actual cubic meters
MMBtu	Million British thermal units
mol%	Percent mole basis
MPa	Megapascal
N_2	Nitrogen
N/A	Not applicable
NETL	National Energy Technology Laboratory
NGCC	Natural gas combined cycle
NIST	National Institute of Standards and Technology
NOx	Oxides of nitrogen
NRTL	Non-random two liquid
O_2	Oxygen
PENG-ROB	Peng-Robinson equation of state
STEAM-NBS	Steam table - National Bureau of Standards
STEAM-TA	Steam table
ppmv	Parts per million volume
PRB	Powder River Basin
psia	Pound per square inch absolute
QGESS	Quality Guidelines for Energy Systems
SCR	Selective catalytic reduction process or equipment
SNCR	Selective non-catalytic reduction process or equipment
STEAMNBS	Steam tables
TGTU	Tail gas treatment unit
TRIG	Transport Reactor Integrated Gasifier
TTD	Terminal Temperature Difference
U.S.	United States
USC	Ultra-supercritical
vol%	Percent by volume
°C	Degrees Celsius
°F	Degrees Fahrenheit

1 Introduction

The National Energy Technology Laboratory (NETL) conducts systems analysis studies that require a large number of inputs, from ambient conditions to parameters for Aspen Plus® (Aspen) process blocks. The sheer number of assumptions required makes it impractical to document all of them in each issued report. The purpose of this section of the Quality Guidelines is to document the assumptions most commonly used in systems analysis studies and the basis for those assumptions.

The values and ranges of values presented in this report represent assumptions that have been made in previous studies.

2 Site Conditions and Characteristics

This section provides the conditions and characteristics of sites commonly used in NETL system studies. The sites include locations in Montana, North Dakota, and Wyoming along with International Organization for Standardization (ISO) conditions, representative of a generic Midwest, United States (U.S.) location. Ambient conditions are required for estimating performance of the power plant configurations and to size the equipment so that an accurate cost estimate can be made. The ambient site conditions and characteristics of three locations plus a generic ISO site are presented in Exhibit 2-1 and Exhibit 2-2.

Exhibit 2-1 Site Characteristics

Site Characteristics	Montana (1)	North Dakota (1)	Wyoming (2)	Midwest ISO (3)
Topography	Level	Level	Level	Level
Size (Pulverized Coal or Integrated Gasification Combined Cycle), acres[a]	300	300	300	300
Size (Natural Gas Combined Cycle), acres	100	100	100	100
Transportation	Rail or Highway	Rail or Highway	Rail or Highway	Rail or Highway
Ash/Slag Disposal	Offsite	Offsite	Offsite	Offsite
Water	50% Municipal and 50% Ground water	50% Municipal and 50% Ground water	50% Municipal and 50% Ground water	50% Municipal and 50% Ground water

a. For calculation convenience, acreage values for coal based plants were assumed to be equal.

Exhibit 2-2 Site Conditions

Site Conditions	Montana (1)	North Dakota (1)	Wyoming (2)	Midwest ISO (3)
Elevation, m (ft)	1,036 (3,400)	579 (1,900)	2,042 (6,700)	0 (0)
Barometric Pressure, MPa (psia)	0.090 (13.0)	0.095 (13.8)	0.079 (11.4)	0.101 (14.7)
Average Ambient Dry Bulb Temperature, °C (°F)	5.6 (42)	4.4 (40)	5.6 (42)	15 (59)
Average Ambient Wet Bulb Temperature, °C (°F)	2.8 (37)	2.2 (36)	2.8 (37)	10.8 (51.5)
Design Ambient Relative Humidity, %	62	68	62	60
Cooling Water Temperature, °C (°F)[a]	8.9 (48)	8.3 (47)	8.9 (48)	15.6 (60)
Air composition based on published psychometric data, mass %				
N_2	75.220	75.231	75.186	75.055
O_2	23.049	23.052	23.038	22.998
Ar	1.283	1.283	1.282	1.280
H_2O	0.398	0.384	0.443	0.616
CO_2	0.050	0.050	0.050	0.050
Total	100.00	100.00	100.00	100.00

[a] The cooling water temperature is the cooling tower cooling water exit temperature. This is set to 8.5°F above ambient wet bulb conditions in ISO cases and 11°F otherwise.

The method used to establish site conditions is provided in Exhibit 2-3 so that additional sites can be defined in a consistent manner. These guidelines should be used in the absence of any compelling market-, project-, or site-specific requirements.

Exhibit 2-3 Method to Establish Site Conditions

Site Conditions	Method
Elevation	The site elevation is the average elevation in the state of interest. Average state elevations are available through numerous internet sources, including: http://en.wikipedia.org/wiki/List_of_U.S._states_by_elevation http://www.netstate.com/states/geography/
Barometric Pressure	The barometric pressure of atmospheric air varies with altitude as well as with local weather conditions. Only altitude effects are considered in the pressure calculation (4) as follows **P = 14.696 * (1 - (6.8753 x 10^-6) * Z)^5.2559** Z = Elevation (altitude) in ft P= barometric pressure in psia Barometric pressure, site elevations, and other climate data can also be obtained from the public domains like National Climatic Data Center (www.ncdc.noaa.gov/oa/mpp/freedata.html) and U.S. Geological Survey's National Elevation Dataset (http://ned.usgs.gov//) by searching for locations and specific parameters of interest.

Site Conditions	Method
Design Ambient Dry Bulb Temperature	The dry bulb temperature can be obtained for the site from public domains like National Climatic Data Center (www.ncdc.noaa.gov/oa/mpp/freedata.html) by searching for locations and specific parameters of interest. The yearly temperatures are averaged to obtain the ambient design dry bulb temperature of the particular site in consideration.
Design Ambient Wet Bulb Temperature	With known dry bulb temperature and relative humidity, wet bulb temperature for the site can be obtained from the psychometric chart.
Design Ambient Relative Humidity	The relative humidity for the selected site is available from public domains like National Climatic Data Center (www.ncdc.noaa.gov/oa/mpp/freedata.html) by searching for locations and specific parameters of interest. The average annual relative humidity is considered as the design ambient relative humidity.
Cooling Water Temperature, °C (°F) (5)	Typical cooling tower approach temperatures are in the range of 4.4 to 11.1°C (8 – 20°F) for the power plant applications. Cold water temperatures for NETL systems studies assume an approach to wet bulb of 8.5°F for ISO condition locations and 11°F for the Montana, Wyoming, and North Dakota locations. In all cases the cooling water range is assumed to be 11.1°C (20°F), which sets the cooling water process outlet temperature.
Air Composition, mol%, dry (6)	Standard dry air is mainly composed of N_2 (78.08%), O_2 (20.95%), Argon (0.93%), and CO_2 (0.04%). Air temperature affects potential moisture content. As air temperature rises, its ability to hold water vapor increases significantly. The amount of water vapor in air at ground level can vary from almost zero to about five percent. Knowing the water vapor content, the remaining constituents can be calculated based on dry air composition. Water vapor content can be obtained from the psychometric chart or another relevant method.

3 Property Methods

A summary of the property methods used for modeling various sections of energy systems is given in Exhibit 3-1.

Exhibit 3-1 Property Methods

Section	Property Method
Gasification and Coal Boiler	Peng-Robinson (PENG-ROB)
Compressor and Gas Turbine	PENG-ROB
HRSG and Steam Turbine	Steam tables (STEAM-NBS)
Sour Water System	PENG-ROB and Non-Random Two Liquid (NRTL)
Sulfur Recovery Unit	PENG-ROB
CO_2 Capture	PENG-ROB
CO_2 Compression	Lee-Kesler-Plöcker (LK-PLOCK)

The gas side modeling for the gasification and boiler systems uses the PENG-ROB equation of state based on the Aspen User Manual (7) recommendations and an evaluation of high-temperature syngas quench systems conducted by the National Institute of Standards and Technology (NIST) for the Electric Power Research Institute (EPRI). (8)

Steam turbines and the steam side of heat recovery steam generators (HRSG) are modeled using steam table property values. The steam table is the standard for water-based systems, and uses an enthalpy reference state of the triple point of water at 32.02°F and 0.089 psia. Aspen recommends the steam table (STEAM-NBS) property method for pure water and steam, and in particular for the free-water phase, when present. The STEAM-NBS property method is based on the 1984 NBS/NRC steam table correlations for thermodynamic properties. These correlations minimize continuity problems that occur at the boundaries between regions of the P-T space and can lead to Aspen model convergence problems. Because the steam tables are a common source of enthalpy data, all enthalpy values in NETL system studies are adjusted to the steam table reference conditions as described in Section 4 of the Guidelines.

In integrated gasification combined cycle (IGCC) plants, the sour water system uses the PENG-ROB equation of state with the exception of the chloride removal process, which uses the Non-Random Two Liquid (NRTL) property method. The NRTL method more accurately predicts the solubility of chlorides in water.

The sulfur recovery unit and CO_2 capture process use the PENG-ROB equation of state. According to Aspen, "this property method is particularly suitable in the high temperature and high pressure regions, such as in hydrocarbon processing applications or supercritical extractions." (7)

The CO_2 compression system uses the Lee-Kesler-Plöcker (LK-PLOCK) equation of state based on discussions with CO_2 compressor vendors concerning the performance predictability of various equation of state models. According to Aspen, "The LK-PLOCK property method is consistent in the critical region." (7)

The property methods of smaller process subsystems in each model should be specified based on the surrounding model blocks and streams to ensure consistency in the balance calculations unless there are compelling reasons to do otherwise.

Between each block or system of blocks that use differing property methods, there should be a stream class changer type manipulator block. This will ensure Aspen performs accurate energy balances.

4 Process Parameters for Modeling

The process parameters used for Aspen and spreadsheet modeling are documented in the following sections. For each parameter associated with a unit operation, a value or range of values is provided. These values represent assumptions that have been made in previous studies.

If no range is presented, it means that all NETL system analyses to date have consistently used the parameter value.

When available, a reference source is provided for the design parameter or range. In many cases, the source is engineering judgment. Additional explanation is provided in the "Notes" column, as warranted.

4.1 STEAM CYCLE ASSUMPTIONS

The range of conditions chosen at the steam turbine throttle valve are representative of currently available commercial offerings for subcritical, supercritical, and ulta-supercritical PC combustion cases, as well as for integrated gasification combined cycle (IGCC) and natural gas combined cycle (NGCC) plants and have been used in past system studies. These values are shown in Exhibit 4-1.

Exhibit 4-1 Steam cycle process parameters

Equipment and Parameter	Value/ Range	Source	Notes
Steam Turbines			
HP Section			
Isentropic Efficiency, %	90.3-91.5	Discussions with steam turbine vendors	
Pressure Ratio, %[a]	25 - 35	Engineering Judgment, (9, p 2-8; 2-16)	
IP Section			
Isentropic Efficiency, %	93.5-94.0	Discussions with steam turbine vendors	
Pressure Ratio, %[a]	6.6 - 14	Engineering Judgment, (10)	
LP[b] Section			
Isentropic Efficiency, %	88.2-89.2	Discussions with steam turbine vendors	These values include exhaust losses.
Pressure Ratio, %[a]	0.7-1.5	Engineering Judgment	
Steam Conditions			
Main Steam Temperature, °C (°F)	538 (1,000) – 760 (1,400)	(11, p 1-14) Engineering Judgment	
Reheat Steam Temperature, °C (°F)	510 – 760 (950 – 1,400)	Engineering Judgment	
Main Steam Pressure, MPa (psi)	12.5 (1,815) – 34.6 (5,015)	(9, p 26-2, 26-7, 2-18)	
Blowdown, % of feedwater flow	0.5-1.0	Engineering Judgment	These values are for subcritical units only.

[a] The pressure ratios are guidelines for each section. In the models, the outlet pressure is specified according to individual case requirements.

[b] Care should be taken regarding the moisture content of the LP exhaust. Typical ranges assumed acceptable are 8-10 mol%

Equipment and Parameter	Value/ Range	Source	Notes
Surface Condenser			
Operating Pressure, MPa (psia)	0.005 – 0.007 (0.698 – 0.982)	(9, p 2-16)	
Terminal Temperature Difference, °C (°F)	11.7 – 12.8 (21 - 23)	(12)	The TTD could be reduced to 5°F, as done in IEA GHG reports (13); however, the TTD was maintained at a higher point in order to maintain consistency with dry and parallel condensers.
Deaerator			
Operating Pressure, MPa (psia)	0.48-0.92 (70-134)	(14, 15)	
Operating Temperature, °C (°F)	148-176 (300-349)	Engineering Judgment	The deaerator maintains a saturated liquid product stream. Therefore the temperature is a function of pressure.

4.2 COAL COMBUSTION AND ASSOCIATED FLUE GAS SYSTEMS

The process parameters listed in this section apply to the gas side of pulverized coal and circulating fluidized bed combustion systems. Exhibit 4-2 presents the parameters for the boiler and combustion air preheater.

Exhibit 4-2 Process Parameters for Coal Combustion Systems

Equipment and Parameter	Value/ Range	Source	Notes
Boiler			
Heat Loss, %	1	(16; 17, p 11; 9, p 23-7)	Heat loss percentage is based on fuel heat input.
Air Infiltration, %	2	(9, p 10-16)	Infiltration air percentage is based on theoretical (stoichiometric) air.
Excess Air Based on Flue Gas O_2 Content, vol%	2.7	(9, p 10-15)	Design parameter is on a dry basis upstream of the air heater.
Combustion Air Preheater			
Air Leakage, %	5.5	(9, 20-13)	Air leakage is 5.5% of total combustion air flow and divided between primary and secondary air based on a ratio of pressure drops between the fan outlet and the air heater.
Flue Gas Exit Temperature, °C (°F)	132 – 177 (270 – 350)	Engineering Judgment	The minimum flue gas temperature is dictated by the flue gas acid dew point.

Exhibit 4-3 presents the parameters associated with flue gas cleanup processes, such as processes designed to remove NOx, sulfur, particulate matter, and mercury.

Exhibit 4-3 Process Parameters for Environmental Systems Associated with Coal Combustion

Equipment and Parameter	Value/ Range	Source	Notes
SCR			
Operating Temperature, °C (°F)	343 – 399 (650 – 750)	(9, p 34-4)	SCR is used in PC cases.
Catalyst		(9, p 34-5)	Titanium/ Vanadium Oxide
NOx Reduction, %	65 - 90	(9, p 29-3)	NOx production and removal are estimated.
Ammonia Slip, ppmv	1 – 5	(18)	
SNCR			
Operating Temperature, °C (°F)	760 – 1,093 (1,400 – 2,000)	(9, p 32-9)	SNCR is used in CFB cases but not modeled in Aspen.
NOx Reduction, %	46	(9, p 29-23)	Assumed NOx inlet concentration of 0.13 lb/MMBtu.
Ammonia Slip, ppmv	1 - 5	(19)	
Baghouse			
Pressure Drop, %	1.5	(9, p 33-10)	
Particulate Removal Efficiency, %	99.5 – 99.98	(9, 32-10)	Range depends on inlet solids loading (including solids from dry FGD applications).
Activated Carbon Injection			
Carbon Feed Rate, kg/MMacm (lb/MMacf)	0 – 24 (0 – 1.5)	(9, p 32-11)	
Hg Removal Efficiency, %	90 – 91.5	(9, 32-11)	Combined co-benefit capture and ACI
Dry FGD Absorber Module			
SO_2 Removal Efficiency,%	93	(9, p 35-12)	Used with low sulfur PRB and lignite coals.
Exit Temperature, °C (°F)	13.8 - 19.4 (25 – 35)	(9, p 32-9)	Range is degrees above adiabatic saturation temperature.
Pressure Drop, %	3.1	Engineering Judgment	
Wet FGD Absorber Module			
SO_2 Removal Efficiency,%	98-99+	(9, p 32-9)	Used with high sulfur bituminous coal.
Exit Temperature, °C (°F)	57 (135)	(9, p 35-3)	
Pressure Drop, %	2.6	(9, p 35-3)	

4.3 GASIFICATION AND ASSOCIATED SYNGAS SYSTEMS

Exhibit 4-4 provides a list of reports where performance data can be obtained for various types of gasifiers.

Exhibit 4-4 Gasifier Performance Data Reports

Gasifier Type	Report Name
GE	Cost and Performance for Fossil Energy Plants" Volume 1: Bituminous Coal and Natural Gas to Electricity, DOE/NETL-2010/1397 (also referred to as Bituminous Baseline Studies) (3)
CoP	Cost and Performance Baseline for Fossil Energy Plants - Volume 3: Low Rank Coal and Natural Gas to Electricity, DOE/NETL-2010/1399 (also referred to as Low-Rank Baseline Studies) (1) Bituminous Baseline Studies (3)
Shell	Low-Rank Baseline Studies (1) Bituminous Baseline Studies (3)
Siemens	Low-Rank Baseline Studies (1)
TRIG	Low-Rank Baseline Studies (1)

The syngas processing, sour water, and mercury removal systems unit operation data are given in Exhibit 4-5.

Exhibit 4-5 Syngas Processing Systems Unit Operation Data

Equipment and Parameter	Value/ Range	Source	Notes
Syngas Scrubbing Tower			
Syngas Exit Temperature, °C (°F)	4.4 (8)	(20, 21)	Degrees below dew point of treated syngas stream.
Pressure Drop, %	1.2	(20, 21)	
Sour CO-Shift[c]			
Temperature Approach to equilibrium, °C (°F)	6 (10)	Engineering Judgment	
Inlet temperature above dew point, °C (°F)	28 (50)	Engineering Judgment	
HTS Pressure Drop, %	1.3	(22, 23)	
LTS Pressure Drop, %	0.6		
COS/HCN Hydrolysis Reactor[d]			
Catalyst		(22, 24)	Activated alumina based catalysts.
Pressure Drop, %	1.3	(22, 24)	

[c] Used in CO_2 capture plants
[d] Used in non-CO_2 capture plants

Equipment and Parameter	Value/ Range	Source	Notes
COS Conversion efficiency, %	95	Discussions with COS Hydrolysis vendor	This value is associated with a catalyst volume of 60 m^3 and an approach to equilibrium of 24°F.
Inlet temperature above dew point, °C (°F)[e]	16.7 (30)	Discussions with COS Hydrolysis vendor	
Low Temperature Gas Cooling			
Outlet Temperature, °C (°F)	35 (95)	(20)	
Mercury Removal Bed Preheater			
Outlet Temperature, °C (°F)	2.8 (5)	(25)	Degrees above the syngas dew point temperature.
Mercury Removal Bed			
Adsorbent Type		(26)	Sulfur-impregnated activated carbon.
Operating Temperature, °C (°F)	30-41 (86-103)	(26)	
Pressure Drop, %	0.7	(26)	
Removal Efficiency,%	90-95	(26)	
Space Velocity, hr^{-1}	4,000	(26)	

The sulfur processing system unit operation data is given in Exhibit 4-6.

Exhibit 4-6 Sulfur Processing Systems Unit Operation Data

Equipment and Parameter	Value/ Range	Source	Notes
Claus Reaction Furnace			
Furnace Temperature, °C (°F)	1,094-1,649 (2,000-3,000)	(27)	Parameter value is minimum required for ammonia destruction.
Pressure Drop, %	2	(27)	
Claus Waste Heat Boiler			
Outlet Temperature, °C (°F)	316-427 (600-800)	(28)	
Steam Pressure, MPa (psia)	3.0 (430)	(28)	Steam generated.

[e] A COS Hydrolysis vendor suggested that the conversion rate would increase with decreasing temperatures, with the minimum inlet temperature suggested at 250°F. However, the conversion rate would decrease with decreasing water composition.

Equipment and Parameter	Value/ Range	Source	Notes
Claus Condenser			
Outlet Temperature, °C (°F)	171-191 (340-375)	(28)	
Steam Pressure, MPa (psia)	0.38-0.55 (55-80)	(28)	Steam generated.
Claus Air Preheater			
Outlet Temperature, °C (°F)	216-232 (420-450)	(28)	
Claus Reactor			
Catalyst		(28)	Alumina based with promoting agents.
Exit Temperature, °C (°F)	278-344 (532-650)	(28)	
Steam Pressure, MPa (psia)	0.38-0.55 (55-80)	(28)	Steam generated.
Pressure Drop, %	2	(28)	
Claus Final Condenser			
Exit Temperature, °C (°F)	121-149 (250-300)	(28)	
Generated Steam Pressure, MPa (psia)	0.20-0.45 (30-65)	(28)	Steam generated.
Pressure Drop, %	2	(28)	
Sulfur recovery, %	97.5-99.9	(28)	

The tail gas treatment system unit operation data is given in Exhibit 4-7.

Exhibit 4-7 Tail Gas Treatment Systems Unit Operation Data

Equipment and Parameter	Value/ Range	Source	Notes
TGTU Hydrogenation Reactor			
Catalyst		(29)	Cobalt molybdate on alumina.
Operating Temperature, °C (°F)	204-293 (400-560)	(29)	
TGTU Waste Heat Boiler			
LP Steam, MPa (psia)	0.3-0.5 (43.5-72.5)	(30)	Steam generated.

4.4 ANCILLARY SYSTEMS

This section contains specifications for ancillary process systems common to many types of cycles.

Exhibit 4-8 Process Parameters for Cooling Water Systems

Equipment and Parameter	Value/ Range	Source	Notes
Wet Cooling Tower			
Cooling Water Range, °C (°F)	11 (20)	(31, p 9-95)	
Evaporative Losses, % of Circulating Water Flow	0.8	(31, p 9-95)	
Drift Losses, % of Circulating Water Flow	0.001	(31, p 9-95)	
Blowdown Losses [Evaporative Losses/(Cycles of Concentration-1)]	4	(31, p 9-95)	Note - The cycles of concentration are a measure of water quality, and a mid-range value was assumed.
Air cooled condenser			
Fan Power Ratio	3 - 4	(32)	Ratio of dry cooling tower power requirement relative to a wet cooling tower design of the same heat duty. This ratio is applicable to ISO conditions only; it could vary significantly based on seasonal and geographical conditions.

4.5 MISCELLANEOUS EQUIPMENT

Exhibit 4-9 provides a table of parameters for a variety of equipment including pumps, fans, blowers, heat exchangers, dryers, compressors, generators, and motors.

Exhibit 4-9 Miscellaneous equipment parameters

Equipment and Parameter	Value/ Range	Source	Notes
Pumps			
Centrifugal			
Efficiency, %	65 - 80	Engineering Judgment	Condensate, Boiler Feed Water, Sour Water Stripper, Limestone Slurry Feed.
Pressure Rise, MPa (psia)	0.3 – 31.92 (44 – 4,630)	(9, P 2-16; 2-18; 35-10)	Pressure rise depends on application.

Equipment and Parameter	Value/ Range	Source	Notes
Fans and Blowers			
Backward Curved Blade			
Polytropic Efficiency, %	75	(33)	Primary Air, Forced Draft, and Induced Draft.
Pressure Rise, kPa (psi)	3.8-10.5 (0.56 -1.52)	(9, P 25-12)	Pressure rise depends on application.
Radial Tipped Blade			
Polytropic Efficiency, %	65	(33)	Oxidation Air Blowers.
Pressure Rise, kPa (psi)	310.3 (45)	(9, P 25-12)	
Shell and Tube Heat Exchangers			
Gas Side			
Pressure Drop, %	2	Engineering Judgment	
Liquid Side			
Pressure Drop, %	4	Engineering Judgment	
Gas-Gas			
Cold/Hot End Temperature Approach, °C (°F)	28 (50)	(9, p 27-16)	
Gas-Liquid			
Cold/Hot End Temperature Approach, °C (°F)	14 (25)	(9, p 27-16)	
Liquid-Liquid			
Cold/Hot End Temperature Approach, °C (°F)	5.5 (10)	(9, p 2-16)	Feed Water Heaters
Compressors			
Centrifugal			
Polytropic Efficiency, %	75 - 85	(20, 25)	Nitrogen, Oxygen, Main Air with Intercooling, CO_2, Syngas Recycle.
Stage Pressure Ratio	1.1 - 2.5	(20, 25, 34)	Range reflects variety of applications.
Mechanical Stage Efficiency, %	98	Engineering Judgment	
Miscellaneous			
Knockout Drum			
Pressure Drop, %	2	(20, 24)	

Equipment and Parameter	Value/ Range	Source	Notes
Generators and Motors			
Generator Efficiency, %	98.5-99.0	Engineering Judgment	Applied to turbine power production.
Electric Motor Efficiency, %	95.0-97.0	Engineering Judgment	Applied to auxiliary power.
motor sizes < 1,000 kW, %	95.0%		
motor sizes > 1,000 kW and < 10,000 kW, %	96.5%		
motor sizes > 10,000 kW, %	97.0%		
HRSG			
Pressure Drop, %	3.3	Engineering Judgment	

5 Revision Control

Exhibit 5-1 Revision table

Revision Number	Revision Date	Description of Change	Comments
1	March 10, 2014	Document formatted and edited	
2	May 13, 2014	Minor updates to address comments	

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